Statement of David L. Bodde
Assistant Director
Natural Resources and Commerce
Congressional Budget Office

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Mr. Chairman, I am pleased to appear before your committee to discuss the financial condition of the nation's electric utilities and what that condition implies for reliable and efficient electric service. Most of the industry has recovered from the acute financal distress of the 1970s and early 1980s. The circumstances of individual utilities, however, differ markedly. A number of companies remain under serious financial stress, and a few may be candidates for bankruptcy. The economic consequences of this are speculative, but it seems unlikely that bankruptcy, by itself, would cause interruptions in electric supply.

For the long term, the central issue is how to provide regulatory incentives for utilities to invest in the most cost-effective generation and transmission. The problem is less the unavailability of electricity at any price than it is generation with equipment not well matched to the task.

CURRENT FINANCIAL CONDITONS

Most investor-owned utilities are in better financial condition today than at any time in recent years. Industry-wide liquidity, measured by the ratio of cash flow to dividend payments, stood at 2.7 in 1984, well above the 2.0 usually considered a prudent minimum. The recovery of the industry has been reflected in its common stock: by the end of May 1985, the market-to-book ratio (the market value of common stock divided by the depreciated book value of the utility's assets) for the industry as a whole stood at 108 percent, a marked contrast to the 73 percent of 1980.

The current health of the industry has grown out of a reversal of many factors that led the utilities into decline in the 1970s. The economic recovery contributed to a revival in the demand for electricity; many utilities finished the construction programs undertaken during the 1970s; other utilities cancelled plants that had become too costly or that would have led to excessive reserve margins; and fuel prices and interest rates declined.

Despite these improved circumstances, the financial condition of a number of companies remains poor. In 1984, 14 of the 100 largest investor-owned utilities had cash flow coverage of 1.5 or less. Currently, the common equity of eight utilities is valued by the market at less than 75 percent of book value. In general, financially stressed companies such as these are trying to complete large construction programs that will yield reserve margins well above those needed for assured supply. At the same time, load growth over the next decade is forecast to be well below the industry average. Thus, growth in demand will not quickly relieve their excess capacity. These construction programs have also been quite expensive, with capacity additions costing 6 to 8 times more than originally projected. Most of this cost remains unrecovered from ratepayers, and its treatment is the central near-term issue for the electric utilities and their regulators.

THE NEAR-TERM ISSUE OF COST ALLOCATION

In most cases, state regulatory commissions allocate construction costs among ratepayers and stockholders. These regulators judge whether the construction expenditures were prudently incurred by the utility, and whether the completed plant is needed to meet current demand. Either test can lead a commission to exclude some or all of the cost of a completed plant from the rate base. The magnitude of these costs, however, makes this a difficult choice — both for the financially stressed utilities and for their rate commissions.

If regulators allowed full and immediate recovery of all construction costs incurred by the most distressed utilities, the first-year price increases in their service areas could range from 15 percent to 70 percent. Such increases would depress economic activity and lower the demand for electricity. But state regulators could also withhold recovery of a large portion of this cost, finding it to be imprudent, incurred for unneeded facilities, or both. Utilities in poor financial condition might lack the flexibility to accommodate such action, and several have stated it would force bankruptcy. If a bankruptcy occurred, the utility (or its creditors) would first file for reorganization under Chapter 11 of the bankruptcy code. A court-appointed trustee would then operate the company during the reorganization period to ensure continued electric service and company operations. The bankruptcy court would also decide how the utility's suppliers, creditors, and stockholders would be compensated, but the state regulators would probably have to approve any change in electric rates that might result. The economic outcome of these proceedings would be unique to each bankruptcy case.

Thus, financially troubled utilities and their regulators face a twofold problem. The rapid cost recovery that would relieve a utility's financial stress would also depress the demand for electricity in its service area, perhaps leading to further rate increases as fixed costs have to be spread over a smaller sales base. But postponing recovery of a large portion of these construction costs (or excluding them entirely) could leave the utility in financial peril and encourage the use of electricity by keeping prices artificially low.

The available evidence suggests that, in most cases, the outcome will be a division of cost between the ratepayers and their utilities that avoids bankruptcy but leaves these few utilities financially weakened. The long-term supply of electricity, however, is less sensitive to this allocation of cost than to the more general incentives provided by utility ratemaking.

THE LONG-TERM SUPPLY OF ELECTRICITY

The long-term concern with the utility industry is sometimes stated in terms of shortfalls in electric supply. It is misleading, however, to infer future shortages simply by comparing capacity now in place with demand under various growth scenarios. To be sure, any growth in demand will eventually require additional generating capacity. But only the most myopic rate regulation would force a shortage by preventing a utility from either building its own capacity or purchasing electricity from a neighboring system. The real issue is whether current ratemaking practices encourage the most economic and capacity additions.

Demand Forecasts and Investment Planning

For the nation as a whole, reserve margins are currently above 35 percent, and should remain at this level in the next few years as plants now under construction are brought into service. But utilities must plan their investments around demand forecasts that look 10 or more years into the future. These forecasts suggest nationwide demand growth ranging from 1 percent to 4 percent, and individual utilities may face even greater variation. Power purchased from neighboring systems (or cogenerators) together with load management can provide some flexibility by postponing the need to build new generating capacity. But as these options become exhausted, utility managers must decide whether to meet expected demand growth by beginning baseload plants well in advance of their service date, or whether to defer such additions until demand growth can be more clearly seen.

Either choice risks economic losses. A decision to build baseload capacity 1/ to meet projected demand can require a major commitment of capital beginning many years before the service date of the plant. If the demand forecast was accurate, the baseload plant could provide the electricity at a lower cost than any other alternative. But actual demand less than that anticipated when the decision was made will create losses from the carrying costs of the underused investment. For example, the

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1. The supply options available to a utility are not limited to very large (over 1,000 MWe) central station powerplants, but also include highly efficient smaller or modular units. Some of these may be equally capital intensive as measured by the cost of a kilowatt of capacity, but their size reduces the utility's financial exposure. See testimony of Dr. Richard E. Rowberg, Office of Technology Assessment, before the Committee on Energy and National Resources, United States Senate, July 25, 1985.

carrying charges for a $1 billion investment would be $100 million per year at a 10 percent interest rate.

On the other hand, a decision to postpone construction would risk meeting higher than expected demand with units not designed for baseload service. These units are less capital intensive than baseload plants and can be built more quickly, thus reducing the financial exposure of the utility. But in baseload service, these advantages are offset by significantly higher operation and fuel costs.

Thus, investment decisions in the electric utility industry require a balancing of risks. 2/ The task of regulation is to allow utility managers to make such choices on their economic and technical merits without regulatory bias either for or against new construction. In many cases, current practice falls short of that ideal.

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2. Simulations of the relative economic cost of excess capacity versus less efficient capacity suggest both to be comparable in size. Falling prices for fossil fuels, however, could significantly reduce the penalties from inefficiency.

Regulation and Investment Decisions

Ratemaking can influence a utility's decision to invest by making the recovery of construction costs more uncertain than the recovery of fuel and operating costs. Construction charges are often held in a separate account outside the rate base rather than reflected in the price of electricity. Once the plant is placed in service, the accumulated amount, together with a return earned on it, is placed in the rate base for recovery.

This practice can lead to several difficulties. Electricity consumers are first shielded from one price effect of their consumption — the need for new capacity — and later presented with sharp rate increases. At the same time, the utility's capacity to make additional investments is constrained by cash flow limitations and the recognition by investors that business risk has been increased by the lower quality of earnings.

The most important issue, however, is the implicit treatment of risk. If the demand for electricity proves to be less than that forseen when the plant was begun, the utility may be required to bear the carrying costs of the excess capacity until it becomes "used and useful". By contrast, the costs of less efficient generation tend to be more easily and quickly recovered through fuel adjustment and operating charges. To the extent that this happens, economic decisionmaking is biased against incurring capital charges and toward fuel and operating expenditures. This could lead to a stock of generating equipment less suited to its task than if the investments had been made with a more balanced regulatory treatment of risk.

THE FEDERAL ROLE

Traditionally, the major role in providing electricity has been left to the investor-owned utility companies and their state regulators. The available evidence suggests that in most cases these institutions can reconcile the cash flow needs of the financially stressed utilities with the price increases imposed on ratepayers. Sales of electricity among utility systems has increased markedly, thus helping to balance overcapacity with the demand for economic generation; and, incipient mergers may strengthen the financial resources of some utility systems. Thus, the need for special federal intervention in the near-term financial situation does not seem large. For the long run, however, the Congress might consider ways to improve competition and investment efficiency.

Fuel Use Restrictions. The Fuel Use Act, as amended, generally prohibits the construction of new generating stations fueled by oil or natural gas. The deregulation of oil and gas markets, together with the prospect of further reductions in the price of these fuels, suggests that these prohibitions be reconsidered. The removal of the gas restriction would yield environmental benefits, stimulate interfuel competition, and encourage utility investments based on the economics of electricity production. Removing the oil restriction as well would further increase interfuel competition, but would also leave the utilities and their customers more vulnerable to any future disruptions in oil supply.

Federal Guidelines. Federal guidelines for state regulation might also be considered. These could be similar in concept to the standards that the Public Utility Regulatory Policies Act of 1978 required states to consider (but not adopt). The guidelines could suggest state approaches to cost-effective investment through more balanced treatment of the risks of excess capacity and less efficient generation.

For example, state regulatory commissions could consider better ways to share the responsibility for predicting demand. States could approve (or disapprove, as appropriate) plant costs at several stages in the construction process. This staged review would lower investment risk by guaranteeing eventual cost recovery of the approved portion of the project, even if these costs were not immediately included in the rate base. It would forewarn of changes in demand growth and enable the utility to either abandon construction or mothball the plant for future use if conditions warrant. The State of Indiana has taken this approach in a law enacted in April of this year. Alternatively, some portion of prudently incurred construction costs could be included in the rate base prior to actual service.

Other guidelines might allow the utility a higher rate of return on cost-effective investments. Where new capacity results in net "avoided costs," some portion of the savings could be reflected in utility earnings, thus giving these companies a direct financial stake in least-cost generation. This approach might better balance risk and reward in states seeking ways to give their utilities greater responsibility for the economic outcome of investment decisions. Finally, the use of fuel-adjustment clauses could be amended to encourage fuel-switching investments.

On the other hand, the ability of the federal government to influence state ratemaking has not been large, and it is uncertain how much real effect voluntary guidelines could have. Further, even voluntary guidelines could be seen as a federal intrusion into the traditional prerogatives of state regulation, and thus encounter resistance independent of their economic merit.

CONCLUSION

In summary, Mr. Chairman, the electric utility industry is in better financial condition today than in recent years. Its near-term problem—the severe finacial stress of a few utilities—is not likely to disrupt the supply of electricity, and the federal role here does not seem large.

Over the longer term, there is growing evidence that the utility industry is responding to an increasingly risky business environment by adopting strategies that emphasize flexibility and limit capital exposure. This response is unlikely to lead to widespread physical shortages. However, rate regulation that makes the recovery of capital costs more uncertain than the recovey of fuel and operating costs could bias investment in the direction of less cost-effective equipment. Thus, the long-term issue is to provide regulatory incentives for utilities to use the mix of fuel and capital equipment that best match economic realities.